CHAPTER II. OVERVIEW OF THE NATURAL GAS MARKET

The marketing of natural gas involves a sequence of steps, including:

- Production of natural gas for sale to long distance transmission companies;
- Sales from transmission companies to local distribution companies; and
- Sales from local distribution companies to end users.

The history of the natural gas market is a history of controls that led to changed behavior by gas producers and consumers, unintended economic effects, and unanticipated judicial interpretations and administrative burdens, all of which were subsequently followed by new or different controls. As a result, the gas market is now as much the product of political and regulatory decisions as of economic signals on supply, demand, and prices.

THE EVOLUTION OF NATURAL GAS POLICY

Natural gas regulation was established with the enactment of the Natural Gas Act of 1938 (NGA). Judicial interpretation of the NGA determined the format of subsequent federal gas regulation and the kinds of problems that would eventually arise under it. Knowledge of the history of federal regulation under NGA is, therefore, a necessary first step in understanding the issues surrounding current natural gas policy.

The Natural Gas Act of 1938 and Federal Regulations

The justification for federal intervention in the natural gas market was based on a series of Federal Trade Commission (FTC) reports that documented numerous abuses, including monopolistic control over prices by pipeline companies. As a result, the FTC recommended federal regulation of interstate (but not intrastate) natural gas prices. 1/ Legislators introduced

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1. Interstate gas is produced in one state and sold in another. Intrastate gas is produced and sold within one state.

natural gas bills in the Congress annually from 1935 to 1937, generally as proposals to regulate interstate pipelines in the same fashion as electric utilities. A bill was finally approved by the Congress and signed into law by President Roosevelt as the Natural Gas Act of 1938.

The NGA was designed to control pipeline monopoly in order to protect consumer interests. The act introduced the use of price ceilings for the resale of interstate gas. These prices were calculated according to the traditional public utility method, in which prices were set to cover actual costs plus a reasonable rate of return and depreciation.

The Federal Power Commission (FPC) administered the NGA and first focused its attention on the regulation of pipelines. The scope of NGA was expanded in 1954, however, with the U.S. Supreme Court's decision in Phillips v. Wisconsin. According to the Court's interpretation, the NGA required the FPC to regulate rates charged by natural gas producers, as well as pipelines, for interstate gas. In short, the FPC was given the authority to regulate the wellhead price of interstate natural gas.

The FPC initially set wellhead prices for producers on an individual basis. This laborious procedure required the commission to determine the capital charges and operating costs to be allowed for each producer in order to calculate individual cost-based prices, leading to a huge backlog of cases. As a result, the FPC established producer prices for entire geographic regions, based on regional average production costs and allowed rates of return. The U.S. Supreme Court upheld the concept of area-wide pricing in the Permian Basin Area Rate Case of 1968.

Since the interstate price of gas was set below its market rate, the demand for gas began to exceed supply. In order to increase price incentives for gas production, in 1974 the FPC established a higher price for gas from wells drilled on or after January 1, 1973, thereby introducing the concept of "new" and "old" gas. The FPC also included an annual price escalator and excluded certain state and federal taxes and allowances from the calculation of wellhead prices.

The FPC also recognized that the interstate-intrastate market distinction had become a problem. The regulated interstate market price did not provide adequate incentive to draw supplies from the unregulated intrastate market in which prices were higher. Furthermore, interstate demand remained artificially high because the new, higher gas prices were averaged with the old, low gas prices. Thus, the average price paid by consumers of interstate gas did not reflect its full economic value.

This mode of regulation, together with an absence of regulation in the intrastate market, had produced perverse results by the early 1970s. Gas shortages were beginning to appear in interstate markets. Industrial gas users, who had paid lower rates for interruptible supplies, found themselves facing curtailments. These curtailments resulted in layoffs of workers and consequent pressure on the Congress for action. In contrast, since intrastate gas brought higher prices than regulation allowed in interstate markets, gas supplies were ample in the intrastate market. In response to severe shortages in the interstate market during the winter of 1976-1977, aggravated by the effects of the OPEC embargo of 1973-74, the Congress adopted emergency measures to allocate existing supplies and began the difficult process of revising natural gas pricing policy. The result was the Natural Gas Policy Act of 1978.

The Natural Gas Policy Act of 1978

The Natural Gas Policy Act (NGPA) of 1978 combined price controls and deregulation by creating nationwide price ceilings and by allowing phased deregulation of certain categories of gas. It sought thereby to reduce regulation significantly without major dislocations. An overview of NGPA is presented in Table 1. As the table illustrates, the sections of NGPA can be classified into three major categories: those that provide supply incentives; those that provide consumer protection; and those that promote uniformity in gas markets by regulating intrastate prices.

Supply Incentives. The incentive provisions were designed to increase the nation's natural gas supply. In general, newly discovered gas, as defined in NGPA, is allowed gradually increasing prices projected to reach an assumed equivalent of the price of oil by 1985. 2/ Thereafter, the wellhead price will be decontrolled. Several categories of new gas were defined, each of which was given distinct price and decontrol treatment. The Section 102 category covers gas found outside 2.5 miles of an existing well, gas found 1,000 feet below the completion depth of an existing well, gas from outer continental shelf leases, and production from new reservoirs. The price ceilings allow the gas defined by Section 102 to increase at the annual rate of inflation plus a real growth premium. New onshore gas produced within existing fields is included in Section 103, with its price increasing only at the annual inflation rate. Both Section 102 and Section 103 gas will be deregulated on January 1, 1985. "High-cost" gas is defined in Section 107 to

2. Note that the oil price projected for 1985 in the NGPA is much lower than current oil prices.

TABLE 1. OVERVIEW OF THE NATURAL GAS POLICY ACT OF 1978

Sections	Description	Price Escalation Formula	Status as of 1/1/85
Supply Incentives			
102	New natural gas outside existing fields; new reservoirs; new outer continental shelf fields	Annual inflation plus real growth premium	Deregulated
103	New onshore wells within existing fields	Annual inflation	Deregulated
107	High-cost gas	Deregulated immediately	Deregulated
108	Stripper wells	Same as 102	Regulated
Consumer Protection			
104	Old interstate gas	Same as 103	Regulated
106a	Renegotiated interstate contracts	Same as 103	Regulated
109	All other gas	Same as 103	Regulated
Intrastate Market			
105	Intrastate gas	Tied to new gas prices	Deregulated
106b	Renegotiated intrastate contracts	Same as 103	Deregulated if contract price is greater than $1.00 per thousand cubic feet

include gas from wells drilled below 15,000 feet and that produced from geopressurized brine, coal seams, Devonian shales, and other high-cost sources. This gas was decontrolled immediately.

Consumer Protection. Consumers were to be protected by continued price controls on the gas already in production, termed "old gas." Section 104 sets the ceiling price for natural gas already dedicated to interstate commerce. The maximum lawful price in contracts that are renegotiated is determined by the provisions set forth in Section 106 of NGPA. The Section 106a price is the higher of either the contract price in the expiring contract or $0.54 per million British thermal units (Btus), both escalating at the annual inflation rate. Section 109 is a catch-all category. Each of these categories remains regulated until their gas is exhausted.

Intrastate Gas Regulation. The last major part of NGPA imposed price controls on intrastate gas to limit the ability of intrastate users to bid supplies away from interstate users. For Section 105 gas, the price ceilings are tied to new gas prices (Section 102). Section 106b includes provisions for setting renegotiated intrastate prices that closely follow the methods employed in Section 106a. The intrastate gas categories will, for the most part, be deregulated in 1985.

NATURAL GAS PRODUCTION

Production decisions by gas producers are strongly influenced by regulatory policies. Both the exploration for and production of natural gas fields are influenced by the prices that regulation allows. For example, the NGPA, by giving preferential price treatment to new natural gas fields and high-cost gas, encouraged these activities over the development of existing, lower-cost gas reserves. Thus, the NGPA may have been partly responsible for producers selling higher-cost gas before lower-cost gas, the opposite of behavior patterns found in unregulated markets. Moreover, uncertainty over the future course of wellhead price regulation may inhibit the production and marketing of gas. As will be seen in subsequent sections, many contracts between gas producers and transmission pipelines contain terms that either reflect this uncertainty or distribute between those two parties the risks that regulatory rules will be changed.

SALES TO TRANSMISSION COMPANIES

Interstate transmission (pipeline) companies purchase, sell, and transport gas across state lines. These companies are essentially natural monopolies because of the economies of scale in gas transmission. Consequently, they are treated as public utilities by the Federal Energy Regulatory Commission (FERC), created by the Congress as the successor to the FPC. Sales and transactions are strictly controlled and profits are limited to a specific rate of return based on the value of the pipeline's capital stock. The gas is sold at cost plus the regulated rate of return.

The method of regulating the interstate gas transmission market affects pipeline decisions. Since a pipeline's profits are based on the value of the capital stock and not on operations, lower gas prices do not readily result in higher pipeline profits. In addition, the limited number of competitors within the pipeline companies' territories allows them to pass along costs to distributors, subject mainly to the competition of alternative fuels. These factors limit the incentive for transmission companies to engage in competitive bidding for gas supplies from producers. The pipeline companies, however, do not have an unchecked ability to pass on costs. The higher rates associated with these increased costs could lead to reductions in natural gas demand. This reduction would lead FERC to revise downward the volume of gas on which the pipeline can earn its allowed rate of return. This, in turn, could raise the unit price even further, possibly causing further decreases in demand. Pipeline companies are concerned about the potential downward spiral.

Despite the regulated nature of gas markets, the final terms of the sales agreements between natural gas producers and pipelines are also influenced by the relative bargaining position of the two parties. Some gas producers may have fields close to several pipelines so that they can obtain an array of competitive bids. Or, if the producer has one field with access to only one or two pipelines, he may bargain with these pipelines to link the sale from his first field to a higher price for gas from a second field. Pipeline companies may also offer to pay royalties and severance taxes for producers in order to obtain better contract conditions. Furthermore, there are nonpecuniary factors that enter the negotiating process, such as personal relationships, client dependability, and other reciprocal factors. Thus, producer-pipeline sales agreements, although determined in an environment of regulated prices, are subject to some of the forces that affect business dealings everywhere.

The sales contracts between producers and pipelines generally include three major components: term, volume, and price. The term of a contract stipulates the length of time for which the contract is valid and the conditions necessary for its renewal. Most long-term contracts--greater than 20 years--were negotiated before 1970. Recent contracts are for shorter time periods, reflecting producers' fears of being locked into fixed prices in a period of inflation.

The volume establishes the obligations and rights of the two parties with respect to the amount of gas delivered and purchased. Often volume rather than price is the key contract provision for pipelines, because of pressure to fulfill customer orders and to maintain pipeline utilization as close to capacity as possible. This often leads to long-term contracts with prices pegged to the ceiling prices for various categories of gas under NGPA. Many recent contracts for deregulated gas peg the maximum price to the price of number 2 fuel oil. Other contracts allow prices to be renegotiated periodically. This renegotiated price may be set by oil prices or, often, the weighted average of the three highest gas prices within a certain distance from the gas field. Older long-term contracts have fixed prices and generally do not include conditions for renegotiation. As will be seen, long-term contracts with guaranteed prices may introduce distortions in the gas market.

SALES TO DISTRIBUTORS

Natural gas sales between transmission companies and distributors usually take place across state lines and, hence, are regulated by FERC. In addition, state public utility commissions (PUCs) can influence these transactions since they regulate the costs distributors can pass on to end users. These sales can be considered as wholesale transactions, and the subsequent sales by distributors to the final users as retail.

The wholesale transactions are governed by service agreements that are approved by FERC and state PUCs. These agreements, like the pipeline contracts with producers, also include provisions that specify the term, volume, and price. The price in a service agreement is determined by FERC, based on rate schedules that establish different prices for various conditions of the sale. These rate schedules have two major cost components: the purchase price of the gas paid by the transmission company to the producer, including any severance taxes, and transportation costs. The latter include a return on the pipeline's investment, depreciation, interest, operations and maintenance, and property and income taxes.

Distribution companies purchase gas from pipelines at a single price that is an average of old, low-cost gas, higher-cost new gas, and high-cost supplemental gas, such as imported liquefied natural gas. To the extent that large volumes of low-cost gas are available, distributors and, ultimately, users are shielded from the higher incremental costs of the other gas. The average cost pricing practiced in the industry reduces the marketing risk associated with the purchase of high-cost gas. Thus, if a hypothetical pipeline has contracts for half its gas at a price of $2.00, and faces a market price for gas of $4.00, it can buy new gas at a price up to $6.00 and still sell

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it without incurring a loss. Therefore, the pipelines can sell gas whose cost is above its market value.

Integrated companies that produce and transport natural gas may use an artificially high "transfer price" to shift profits to the production subsidiary. This is advantageous because FERC regulates the rate of return, and, therefore, the profits, of transmission companies. Since some integrated companies have a relatively large cushion of low-cost gas, the production subsidiary could sell its gas to the pipeline subsidiary at inflated, illegal prices, thus transferring profits back to the production end. In fact, in some antitrust cases FERC and the U.S. Justice Department have requested that producers provide information on their bids. This monitoring has motivated many producers to send out formal bid requests, in order to document their antitrust compliance.

SALES TO END USERS

The Natural Gas Policy Act of 1978 mandated an "incremental pricing" system. This law requires FERC and state PUCs to establish two categories of gas prices to be paid by different types of final users. The first category applies to industrial boiler users and to other industrial customers determined by FERC. The second price applies to all other users of natural gas, including residential customers. The burden of new higher prices allowed under NGPA is initially placed on customers in the first category. Once all the gas purchased by these users has reached the price ceiling specified by FERC, the price is frozen and any additional sales of higher price gas are borne by customers in the second category. (The price in the first category is set at the Btu equivalent price of an alternative industrial fuel.) The net result of this pricing policy is that gas prices for industrial users have recently been increasing faster than comparable gas prices for electric utility, residential, and commercial users.

The principles for allocating costs over time and among customers are set forth in the prices from the rate schedules determined by FERC. These principles are applied to cost allocation at both the wholesale and retail levels. These costs are based on distance of transport and/or whether customers are firm or interruptible. The former category includes residential customers. The latter category includes industrial and commercial customers who have the necessary equipment to switch fuels at low cost. These customers are willing to accept a contract that could interrupt their gas supply during peak seasons in return for lower rates during the rest of the year. In this case, industrial customers pay only a commodity charge, or a rate based on the amount actually purchased. Firm customers, or those not willing to accept an interruptible service, pay this charge plus an additional fixed monthly charge.

State PUCs determine sectoral rate schedules. Historically, these rates decline as consumption increases, reflecting economies of scale in the gas industry. Increasing costs for new gas supplies in recent years, however, have made such pricing policies inefficient. Therefore, there has been a push by some state PUCs to "flatten" prices and to invert eventually the rate schedules so that natural gas users will make efficient resource allocation decisions and have stronger incentives to reduce gas consumption.

Retail natural gas sales are essentially regulated by state PUCs. FERC, however, has limited power under the Public Utilities Regulatory Policy Act (PURPA) to set ratemaking standards. The state PUCs have jurisdiction over the pass-through of distributor costs to retail customers.

Table 2 presents the consumption of natural gas by end users from 1970 to 1980. Industrial and electric utility use of natural gas constituted

TABLE 2. CONSUMPTION OF NATURAL GAS BY END USERS, CALENDAR YEARS 1970-1981 (In trillions of cubic feet)

Year	Residential	Commercial	Industrial	Electric Utilities	Transportation	Total
1970	4.84	2.40	9.25	3.93	0.72	21.14
1971	4.97	2.51	9.59	3.98	0.74	21.79
1972	5.13	2.61	9.62	3.98	0.77	22.10
1973	4.88	2.60	10.18	3.66	0.73	22.05
1974	4.79	2.56	9.77	3.44	0.67	21.22
1975	4.92	2.51	8.36	3.16	0.58	19.54
1976	5.05	2.67	8.60	3.08	0.55	19.95
1977	4.82	2.50	8.47	3.19	0.53	19.52
1978	4.90	2.60	8.40	3.19	0.53	19.63
1979	4.97	2.79	8.40	3.49	0.60	20.24
1980	4.80	2.70	8.24	3.68	0.59	20.02
1981	4.73	2.66	7.93	3.76	0.63	19.71

SOURCE: U.S. Department of Energy, Energy Information Administration, 1980 Annual Report to Congress, vol. II, DOE/EIA-0173(80)/2 (1980). Data for 1981: U.S. Department of Energy, Monthly Energy Review.

roughly 60 percent of total gas consumption in 1980. 3/ While the industrial share of total natural gas consumption has declined by over 10 percent since 1974, total natural gas consumption has remained virtually constant.

3. Gas utility industry revenues were $38.9 billion in 1979. American Gas Association, Gas Facts, Department of Statistics (1979).

CHAPTER III. EFFECTS OF DECONTROL ON THE NATURAL GAS MARKET

The economic effects of natural gas wellhead price decontrol can be viewed from three perspectives:

- o The economic adjustments in the natural gas market;
- o The effects on the economy as a whole; and
- o The effects on the distribution of income among individuals, regions, and economic sectors.

This chapter develops the first view--adjustments in the natural gas market. Before policymakers can determine the effects of wellhead price policy changes on gas markets, they will need to know the answers to the following questions:

- o What is assumed about the price of oil during decontrol?
- o What is assumed or known about the content of natural gas contracts, specifically, the extent of provisions that tie gas prices to oil prices, to other energy prices, or force pipelines to "take-or-pay" for high-cost gas?
- o How will supply and demand react to changes in gas prices?
- o What policy options exist for ensuring an orderly transition to decontrol?

The decontrol of natural gas prices at the wellhead ultimately would result in aggregate economic benefits through an improved allocation of resources. The higher gas prices that would allow such an adjustment would also redistribute significant amounts of income away from gas consumers (and from the producers of other goods) to gas producers. Special characteristics of the gas market, which are discussed in this chapter, influence the size of both of these effects. These special characteristics would also affect how the natural gas market adjusts after decontrol. A decontrol proposal, therefore, should address these features of the gas market.

WELLHEAD PRICE DECONTROL IN AN IDEAL COMPETITIVE MARKET

It is helpful to begin with a review of the effect of natural gas price decontrol in an ideal situation. Then the idealized picture can be modified to capture the special features of the natural gas market.

Efficiency Gains

Control of natural gas prices--or for that matter, of the price of any commodity--restricts the ability of the economy to improve the allocation of its resources. Removing this restriction would provide any anticipated benefits from decontrol. "Efficiency gains" are the economic benefits that result from improving the allocation of resources through expanded opportunties for exchange. Understanding an efficiency gain is, then, the first step toward understanding the benefits to be derived from the decontrol of natural gas wellhead prices.

Society may have many uses for any given resource. Natural gas, for example, can be burned by households and businesses or used as a feedstock for fertilizer. What is the best allocation of a fixed amount of gas (or any other commodity) among such competing uses? Like the household that allocates a fixed budget to buy the items it values most, society can derive the greatest benefit from its resources by using them in their most highly valued way.

For example, suppose that a steel mill pays $4 for a thousand cubic feet of gas. At the same time, an adjacent petrochemical plant is willing to pay $6 for the same amount of gas to replace the more expensive oil it uses as its feedstock. In this case, an improved allocation of gas between these two users is possible. The petrochemical plant could approach the steel mill and buy its gas for $4. The steel mill could then use the $4 to buy residual oil or coal for its furnace, and end up as well off as before. At the same time, the petrochemical plant has saved $2 relative to the cost of the oil it previously used. This saving may accrue to the plant's stockholders or to its workers in the form of higher wages. Setting aside for a moment any value judgment about distribution, the exchange has clearly improved the aggregate well-being that this hypothetical two-firm economy derives from its resources. Changes in the distribution of this benefit do not reduce its size. The steel mill, aware of its bargaining position, could have charged the petrochemical plant up to $6 for the gas; this would have changed the distribution of well-being, but not the aggregate economic improvement. Regardless of who derives the benefit, $2 is gained in this two-firm economy. This $2 is called an efficiency gain because it is realized by improving the overall efficiency of resource allocation through exchange of goods.

Efficiency gains are sometimes described as "consumers' surplus" or "producers' surplus"--terms that describe ways in which efficiency gains can be realized. To illustrate with another example, a hypothetical household must choose between oil and electricity as a heating fuel at a cost of $1,000 for the winter. New gas capable of delivering the same volume of heat at $800 becomes available. Even though the household is willing to pay $1,000, it no longer has to. By switching to gas, the household can save $200. This $200 difference between what the household was willing to pay and what it actually paid is called "consumers' surplus" and is a type of efficiency gain. The gain is the difference between the market price of a good and the value of the next-best alternative to that good. By another definition, it is the amount a consumer saves by switching from a higher-valued alternative to a cheaper substitute. Consumers' surplus can also occur simply because some goods are cheaper than the price consumers are willing to pay for them. For example, although a household may be willing and able to pay $6.00 for a thousand cubic feet of gas, gas may cost only $4.00. Such a household in effect saves $2.00 by being able to buy gas at the market price, rather than at its subjective value. It may use the difference to buy more gas, more other goods, or to save. But in any case, the savings become part of the household's well-being and of total economic activity.

Similarly, unregulated producers can realize a "producer's surplus," or, conventionally, profit. For example, if a firm can produce a thousand cubic feet of gas for $3.00, but can sell the gas for $5.00, the firm realizes a profit, or a producer's surplus, of $2.00. But the $2.00 is more than profit--it is the added value the economy obtains from transforming materials and labor into natural gas. The $2.00 is added into the economy and generates additional income, investment, and savings. Again leaving aside distributional considerations, producers' surplus has thus raised the value of the goods society can produce from its resources, and, therefore, its well-being (in this instance, transforming $3.00 worth of materials and labor into $5.00 worth of gas). Thus, as long as resources can be transformed into higher-valued goods--through either exchange or production--economic benefits result.

What is the nature of these benefits? In the case of producer's surplus, efficiency gains are translated into increases in national income. This occurs as profits are realized on production, and then invested or distributed as dividends. In either case, the increase in profit becomes an increase in aggregate demand in the economy, experienced either as increased investment (if profits are reinvested, either directly or through savings) or increased consumption of other goods and services.

In the case of consumer's surplus, the effects are less clear. Consider the above example of the consumer who seeks to heat his home for the winter. In this case, the saved $200 becomes an increase in the consumer's disposable income, available for increased consumption or savings. This efficiency gain is directly translated into increased economic activity. Examples can be constructed, however, in which efficiency gains do not translate readily into increased economic activity. For example, suppose that the household discussed above would be willing to pay $6.00 for a thousand cubic feet of gas that costs $4.00 for a saving of $2.00. Perhaps this household's use for gas, and, consequently, the value it assigns to it, increases to $6.50. The market price of gas, however, remains the same. Thus, this household's consumer surplus will not be realized as income, even though the household is now "better off" by an additional $0.50. In this case, although the efficiency gain increases, as does some notion of the household's welfare, these improvements will not be reflected in the national income accounts.

The gains through exchange that are experienced in the natural gas market are generally of the type that create new income--producers' surplus. Increased profits in the natural gas sector can be recognized as increased investment or spending by gas-producing firms and increased employment and economic activity in gas-producing regions. Those households that consume any new natural gas that decontrol might induce would realize efficiency gains as additional disposable income if their consumption of gas displaces the consumption of some other, more expensive, energy source.

The new income that efficiency gains deliver is not realized immediately, however. Like the efficiency gains themselves, the added income that decontrol could create would occur only as resources were reallocated--that is, as more inputs were allocated to natural gas production, as gas deliveries were reallocated to displace higher-priced fuels, and as the economy adapted to higher gas prices. A variety of circumstances would impede this process: the time required to secure new productive inputs, to relocate labor and other factors of production, to plan new gas exploration and production investments, and rigidities in wages and prices. In the absence of these frictional impediments, efficiency gains would be readily translated into increased national income. With these impediments, efficiency gains should be conceived of as an outer bound of increased national income, a "target" level of increased well-being that might or might not ultimately be achieved because of both timing considerations and the fact that some efficiency gains are not translated into income.

This increase in economic activity resulting from higher gas prices, however, would be obtained at the cost of a redistribution of income. The income transfers would occur as consumers pay, and producers receive, the decontrolled price for gas production that would have taken place even at the controlled price. Thus, for those already consuming gas, consumption of other goods or savings would have to decrease. Higher gas prices, therefore, would reduce the real income of these consumers and, in turn, the incomes of those who produce other goods.

Empirical Questions

The description of the adjustments to higher natural gas prices raises two major empirical questions that are applicable to any market. The first concerns the nature of supply and demand in the gas market; these determine the size of the efficiency gains and income transfers associated with gas decontrol. The second question concerns the speed with which these effects occur. While the supply and demand relationships reveal what effects might inevitably occur in a decontrolled gas market, they do not indicate how quickly these effects would take place or in what sequence. This section discusses these topics.

Responsiveness of Supply and Demand. The efficiency gains resulting from wellhead price decontrol would depend directly upon the supply response of gas producers and the demand response of gas consumers. When supply and demand are more responsive to price changes (termed more "price elastic"), the efficiency gains are greater than when they are less responsive. For example, if wellhead price decontrol did not produce increased gas supplies, there would be no additional gas to exchange and, therefore, many of the efficiency gains discussed earlier could not occur. The result would be higher prices and smaller efficiency gains as gas users willing to pay the higher price bid the limited supplies away from those unwilling to pay it. On the other hand, if wellhead price deregulation brought forth ample supplies of gas, users could switch to natural gas from other, more expensive fuels. Unfortunately, the response of gas producers and gas users to wellhead price decontrol cannot be anticipated with great precision and must be assumed. Such assumptions are central to any analysis of changes in natural gas policy.

Lagged Response. The explanations of supply and demand relationships presented in the preceding section gives a static, or one-time, snapshot of market conditions. Even if the supply and demand relationships could be estimated with precision so that the ultimate efficiency gains and income transfers could also be determined, the speed with which these ultimate effects could be realized would still be unknown. While an efficiency gain can be described in theory, it cannot be achieved instantaneously. The efficiency gains resulting from gas decontrol would occur as consumers switched from more expensive alternatives to newly available gas and as each producer combined resources to produce and explore for gas at a profit. Both of these activities take time. New hook-ups require planning by the local distribution company and state public utility commission (PUC), and may require new delivery systems. Investments in new production and exploration must precede the provision of new supplies. Firms require time to compare alternative investments, conduct basic geological work in preparation for drilling, and acquire inputs (for instance, rigs, drillbits, or engineers) that may be in short supply.

Moreover, after decontrol, the time path of rising prices is also uncertain. The equilibrium of supply and demand in a decontrolled market would ultimately be reached, but the path to this new price is ambiguous. Prices might fluctuate during the transition period, perhaps even rising above their new long-term level before reaching their ultimate value. This adds to the uncertainty surrounding the timing and magnitude of demand and supply responses and the realization of efficiency gains. Thus, any analysis of gas decontrol must address two major questions:

- How will gas supply and demand respond to a given change in the price of natural gas and how can an estimate of this response be obtained?

- What estimate of efficiency gains is obtained from these supply and demand responses?

WELLHEAD PRICE DECONTROL IN THE NATURAL GAS MARKET

The previous section discussed the effects of price decontrol in an idealized competitive natural gas market and described two major empirical problems associated with that market. Further refinement is required to analyze natural gas price decontrol, because the natural gas market does not have all of the requisite features of an ideal competitive market. This section shows how the theory of decontrol in a competitive market must be modified to incorporate the peculiarities of the natural gas market today. The existing market conditions that are examined include:

- The Competitiveness of the Natural Gas Market. The competitive behavior of the natural gas market could influence the price paid for additional gas supplies and, therefore, the magnitude of the other effects of decontrol.

- Gas Supply Allocation Policies. Existing gas supplies are now allocated principally by regulation or historic pattern rather than solely by price, as they would be in a free market. Thus, the efficiency gains associated with decontrol would occur not only for new production but also for existing supplies as well.

- Average Cost Pricing Policies (the Fly-Up Problem). Pipelines sell their gas for a price that is the average of all the prices pipelines pay for gas. Since some pipelines have substantial supplies of low-cost gas under old contracts, they may be able to pay more than the long-run market price for additional supplies. This is commonly known as "the fly-up problem." This problem may also create regional economic imbalances. If the reserves of low-cost gas are in fact unevenly distributed among regions, as they most likely are, then regions with these supplies will be more capable of competing for wellhead supplies than their counterparts. Thus, the distribution of old, low-cost gas is an important consideration, as is the content of existing gas contracts in general. Another consideration is whether a skewed distribution of low-cost reserves would lead some pipelines to fail upon decontrol.

- Integration of Suppliers. There are over 12,000 producers of natural gas, enough, in theory, for a competitive market to exist. But some producers also own pipelines that enjoy the status of a regulated monopoly. In the absence of effective regulation, some producers might be able to exercise monopolistic power in some regional natural gas markets.

- State PUC Allocation of Costs Among Customers. State public utility commissions determine the prices that different classes of final users pay for natural gas. Proper allocation of pipeline costs to various users might help ameliorate the adjustment costs that would follow decontrol, while improper regulation could increase them.

The Competitiveness of the Natural Gas Market

Whether or not economic actors are competitive depends largely upon how they make their decisions. A competitive supplier is one who must sell his product for the prevailing price (given his presumed inability to influence prices by manipulating his own level of output), and will continue to offer his product until the cost of producing it is not matched by the price received for it. Similarly, competitive demanders are those that seek to minimize the cost of purchases associated with any level of the satisfaction they derive from their purchases, or, alternatively, seek to maximize the well-being they derive from their expenditures.

The natural gas market is not universally competitive. The major distortions of competitive behavior appear in the regulatory status and behavior of pipeline companies. Pipelines earn their profits by selling enough gas to realize the rate of return allowed them by the Federal Energy Regulatory Commission (FERC). This rate is based on the value of the pipeline's capital assets, and is averaged over a volume of gas sales projected annually, as discussed in Chapter II. Once the pipeline sells this projected volume of gas, it has limited incentive to sell more. In fact, if it does sell more gas, FERC may increase the base volume of sales over which profits can be realized in the subsequent year, reducing the pipeline's future profits should sales fall short of the new, higher target.

On the other hand, if the pipeline fails to meet its projected level of sales, its loss of profits will be limited to that year, as FERC will allow the pipeline a lower level of projected sales to realize its allowed profits in subsequent years. The only constraint on this process is that the pipeline itself remain "used and useful," meaning that some amount of gas must move through it. Thus, pipeline companies have limited incentives to buy gas as cheaply as possible or to sell as much as possible. Rather, the regulation process predisposes these companies to secure large gas reserves, so that the pipelines will remain used and useful for as long a period of time as possible. Indeed, a pipeline company would be motivated to pay a premium for long-term supplies, even in a deregulated market, since the extraordinary capital costs of building a pipeline require some degree of confidence that gas supplies will be available over its productive life. This incentive now is magnified by the existence of a regulatory climate that rewards this behavior. To protect their supplies, pipelines may, therefore, buy gas at a higher price than they would in a strictly competitive market, and automatically pass these added costs along to their customers through "purchased gas" adjustments. Pipelines may also ensure their access to future supplies by agreeing to "take-or-pay" provisions in contracts with producers. These provisions require the buyer to pay for certain quantities of gas at preset prices regardless of whether delivery occurs at the time of payment. This type of noncompetitive behavior must be incorporated into any analysis of the natural gas market, since its existence affects the ultimate prices and quantities of gas in the wellhead market, and the subsequent allocation of that gas among regions and users. To understand the extent of this behavior, any analysis of the gas market must ask:

- o How much gas is contracted under take-or-pay provisions? If take-or-pay provisions are limited by a decontrol proposal, how much will gas prices be affected?

- o Is this estimate assumed or derived from surveys of the gas market?